OCS Report
MMS 92-0070

Investigation of Gas Well Blowout Brazos Area Block A-23 May 30, 1990

Gulf of Mexico
Offshore Texas

MMS
U.S. Department of the Interior
Minerals Management Service
Gulf of Mexico OCS Region

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Bill Dockery
Joe Levine
David Maldonado
Burt Mullin

U.S. Department of the Interior
Minerals Management Service
Gulf of Mexico OCS Regional Office

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Investigation and Report

The Accident

A serious gas well blowout occurred on May 30, 1990, aboard a jackup drilling rig. Wireline operations associated with a well production test were being conducted at the time. The rig, identified as the *Keyes-Marine 303,* was operated by Marine Drilling Company, a drilling contractor. The blowout occurred at the newly drilled Well A-8. The bottomhole location of the well is on Brazos Area Block A-23, Lease OCS-G 3938, in the Gulf of Mexico (GOM), offshore the State of Texas. Norcen Explorer, Inc., (NEI) was the designated operator for the well.

Authority to Investigate and Report

The Minerals Management Service (MMS) is required to investigate and prepare a public report of this accident in compliance with Section 208, Subsections 22(d), (e), and (f), of the Outer Continental Shelf (OCS) Lands Act, as amended in 1978, and in accordance with Department of the Interior Regulations 30 CFR Part 250.

By memorandum dated June 6, 1990, the following MMS personnel were named to the investigative panel:

Bill Dockery, Herndon, Virginia

Joe Levine, Lake Jackson, Texas

David Maldonado, Lake Jackson, Texas

Burt Mullin, New Orleans, Louisiana

Investigation Procedures

All personnel safely evacuated the facility shortly after the blowout began at 6:30 p.m. on May 30, 1990. The District Supervisor and the District Drilling Engineer, MMS, Lake Jackson District, traveled by helicopter to the Brazos A-23 blowout on the morning of May 31, 1990, and took photographs from the air (see Attachment 1), but were unable to land on the *Keyes-Marine 303* because the blowout was still in progress. On June 2, 1990, after the well was brought under control, the District Supervisor and the District Drilling Engineer were able to land on the rig, obtain early information about the accident, and take photographs of the damage caused to the rig and associated equipment. On June 6, 1990, members of the accident investigative panel boarded the *Keyes-Marine 303,* obtained information about the blowout and subsequent activities, and photographed the damage caused to the rig and associated equipment.

The investigative panel convened on June 28, 1990, at the MMS regional office in New Orleans, Louisiana. The following individuals, all present on the rig at the time of the accident, were questioned about the blowout and subsequent activities:

David Hughes, NEI consultant

Wayne Harris, *Keyes-Marine 303* employee

Charles Gentry, *Keyes-Marine 303* employee

Arthur Bryant, Schlumberger employee

Robert D. DeLancey, *Keyes-Marine 303* employee

R. Martin Songe, Halliburton Reservoir Services employee

Jerry Harper, NEI consultant

Background

Lease OCS-G 3938 covers approximately 5,760 acres and is located in the Brazos Area Block A-23, GOM, off the Texas coast. (For lease location, see Attachment 2.) The lease was issued effective March 1, 1979, for a cash bonus of $47,133,000. The original lessee was Shell Oil Company. Shell Offshore Inc. was the lessee of record at the time of this accident.

On November 28, 1989, Shell Offshore Inc. designated NEI as the operator of the SW/4 SW/4; W/2 SE/4 SW/4 of Brazos Area Block A-23. The bottomhole location of Well A-8, the well where the blowout occurred, is within this described area. Shell Offshore Inc. was the operator for the remainder of the block at the time of the blowout. The surface location of Well A-8 is on Brazos Area Block A-22, Lease OCS-G 3937. The designated operator for Brazos Area Block A-22 at the time of the blowout was NEI.

A supplemental Plan of Exploration (POE) to drill locations D and E was submitted on November 22, 1989, and approved on December 14, 1989. Each of the two wells in the POE was to have its surface location on Brazos Area Block A-22, Lease OCS-G 3937, and its bottomhole location on Brazos Area Block A-23, Lease OCS-G 3938. The current lessees of Lease OCS-G 3937 are as follows:

Norcen Explorer, Inc. - 62.5 percent ownership interest

Kentucky Offshore, Inc. - 22.5 percent ownership interest

Badger Oil & Gas Company, Inc. - 15 percent ownership interest

On December 8, 1989, NEI submitted an Application for Permit to Drill (APD) Well A-8 (location E on the POE) in the Brazos Area Block A-23. The APD was subsequently approved.

Findings

Activities Prior to Loss of Well Control

On December 18, 1989, the *Keyes-Marine 303* jackup drilling rig, a cantilever type, completed temporary abandonment operations of Lease OCS-G 3937, Brazos Block A-22, Well A-3, and was skidded to the surface location of Brazos Block A-23, Well A-8. The rig was cantilevered over an existing platform. Well A-8 was spudded on December 20, 1989, through 24-inch outside diameter (OD) drive pipe.

Strings of 20-inch OD conductor, 13⅜-inch OD surface, and 9⅝-inch OD intermediate casing were set and cemented at measured depths (MD) of 1,008 feet, 4,620 feet, and 12,909 feet MD respectively. A 7⅝-inch OD drilling liner was set and cemented from 13,763 feet MD to 12,621 feet MD, and a 5½-inch OD production liner was set and cemented from 14,934 feet MD to 12,903 feet MD. The 5½-inch OD liner was subsequently tied back to the surface. The 5½-inch OD production casing was grade P-110 with mixed weights of 23 and 26 pounds per foot and premium grade threads and couplings. The 23- and 26-pounds-per-foot casing sections had, respectively, 14,530 pounds per square inch (psi) and 16,660 psi minimum internal yield pressure strengths in burst and 14,540 psi and 17,390 psi pressure resistance to collapse. A 4⅜-inch diameter hole was drilled below the production casing using mud weighted to 17.0 pounds per gallon (ppg). Total depth was reached on May 3, 1990. Drilling tools were stuck while drilling the 4⅜-inch diameter hole and were abandoned in the open-hole section. In preparation for a production evaluation test on the open-hole section, a tubing test string, retrievable casing packer, and other downhole test tools were run. A test tree, flowline, and other surface production process and measurement equipment and control devices were installed. The test tree, its component valves, the flowline, and other components of the surface test apparatus were pressure tested to 10,000 psi, first using water and then nitrogen gas. A 13½-hour production test was then conducted. The test was terminated at 7:05 p.m. on May 20, 1990. The open-hole section produced formation water at a rate of 26 barrels per day with a trace of gas. The test tools were then pulled out of the well. The 4⅜-inch diameter open-hole section was abandoned by setting a bridge plug inside the 5½-inch OD casing.

In preparation for a production evaluation test (flow test) on a gas-bearing zone of interest behind the 5½-inch OD production casing, a seal-bore-type packer was run and set. Below the packer was an assembly consisting of a wireline re-entry guide and two selective landing nipples. A tubing test string with a seal assembly at the bottom was run, the seal assembly was inserted into the packer bore, and the test string was spaced out. In the process, steps were taken to create an underbalanced condition. The interval of interest was then perforated. The tubing was 2⅞-inch OD, grade P-105, 7.9 pounds-per-foot weight with premium grade upset tubing connections. Tubing strength was 17,640 psi minimum internal yield pressure in burst and 18,220 psi pressure resistance to collapse.

During this flow test, a 15,000-psi-rated working pressure (RWP) test tree was connected to the top of the tubing test string, and a 13⅝-inch inside diameter (ID) blowout preventer (BOP) stack with 10,000-psi RWP rams and a 5,000-psi RWP annular preventer was in place on the 5½-inch OD production casing, as shown in Attachment 3. The BOP stack arrangement, proceeding from the bottom to the top, was (1) blind-shear rams, (2) pipe rams, (3) drilling spool, (4) blind rams, (5) pipe rams, and (6) annular preventer. The choke and kill manifold and piping system had an RWP of 10,000 psi. The upper pipe rams were closed on the tubing. All other preventers in the BOP stack were open. The master and swab valves in the test tree were manually operated plug-type valves. The tubing was set in the slips in the rotary table, the test tree tied down with chains to the rig structure (see Attachment 4), and the lubricator held at its top by the elevators. A leaking swab valve was replaced with a shop-tested valve of the same manufacture during the time interval between the end of the open-hole test and this flow test. Otherwise, the same test tree and valves were used for both tests.

Prior to flowing the well, 1,000-psi pressure was applied and held on the 5½-inch OD casing by 2⅞-inch OD tubing annulus through the 3-inch ID kill line on the BOP stack. This pressure was applied with the rig mud pumps as part of a plan to monitor the annulus for tubing leaks during the test. The remotely controlled, hydraulically operated valve (hereinafter referred to as an HCR) and the manual valve on the kill line at the spool in the BOP stack were left open. The flow path in the kill line ran from the casing annulus, to the choke-and-kill manifold, to a standpipe manifold on the rig floor, and on to the rig mud pumps. The HCR and manual valve on the choke line at the spool in the BOP stack were in a closed position before the accident and remained closed until kill operations began.

The well was flowed through $^{9}/_{64}$-, $^{10}/_{64}$-, $^{11}/_{64}$-, and $^{12}/_{64}$-inch choke sizes. Maximum flow rates were achieved on the $^{12}/_{64}$-inch choke, yielding 24-hour flow rates of 5.247 million cubic feet of gas, 42 barrels of condensate, and 122 barrels of water. Flowing tubing pressure on the $^{12}/_{64}$-inch choke was measured as 7,200 psi and shut-in surface tubing pressure as 9,200 psi. Produced fluids were routed through flow-control and measurement equipment and through a heater and separator. The produced gas was burned at a flare boom. The 45-hour test was terminated at 11:09 p.m. on May 28, 1990, by closing the two 15,000-psi RWP master valves in the test tree. (See Attachment 3.)

Loss of Well Control

Plans were to isolate the perforated interval after the test, then perforate and test an upper zone. In order to isolate the perforated interval, several unsuccessful attempts were made at setting a tubing plug in a selective landing nipple below the packer by use of a wireline.

During one of the wireline runs, a leak was detected in the lower master valve. Operations were continued with the valve known to be defective. The tubing string was not equipped with a downhole safety valve. Reliance was thus placed on the upper master valve to serve as a primary control device. In case of a subsequent failure of the upper master valve, backup means were available to confine well pressure within the surface control system. The backup means were (1) closure of the bleed valve on the flowline at the floor manifold to confine pressure to within the flowline, test tree, and lubricator; (2) closure of the sliding sleeve valve on the test tree to confine pressure within the test tree and lubricator; (3) closure of the sliding sleeve valve and the swab valve to confine pressure within the test tree; and (4) closure of the sliding sleeve valve and the wireline BOP's to confine pressure within the test tree and that section of the lubricator located below the uppermost closed BOP.

The well was shut in by closing the two master valves on the test tree, and a wireline unit with a conductor cable was used to run a cast-iron bridge plug (CIBP). A 15,000-psi RWP lubricator with three remotely controlled wireline blowout preventers and an overall length of approximately 60 feet was installed on a flange connection at the top of the test tree. Differential pressure across the closed master valves was equalized by using a high-pressure pump to inject water into the flowline, test tree, and lubricator. The master valves were then opened. The CIBP was then run on the conductor cable to isolate the wellbore below the packer. The CIBP was run with an intent to set it inside a 2⅞-inch OD tubing pup joint located between the bottom landing nipple and the wireline re-entry guide. Surface indications in the wireline unit were that the CIBP had set in a normal manner. The wireline tools were then pulled back into the lubricator. Subsequent investigation showed that the CIBP had not set. Remnants of the CIBP were found inside the test tree. During the wireline runs, all valves in the test tree, including the sliding sleeve valve, were open and the bleed valve on the flowline at the floor manifold was closed. This procedure allowed 9,200-psi shut-in well pressure to remain on the flowline during the wireline runs.

At approximately 6:00 p.m. on May 30, 1990, after the wireline tools were brought inside the lubricator, the two master valves were closed to isolate the upper portion of the test tree, the lubricator, and the flowline from well pressure. The sliding sleeve valve and the uppermost valve (swab valve) in the test tree were left open. The lower master valve was closed although it was known prior to the CIBP run that the valve would not hold pressure.

In preparation for removing the wireline tools from the lubricator, the 9,200-psi shut-in well pressure in the flowline, lubricator, and test tree above the closed master valves was bled down by opening the bleed valve on the flowline at the floor manifold. The released gas was routed through a choke and vented into the atmosphere at a flare boom. The RWP of the 2-inch ID flowline was 15,000 psi. The lubricator was equipped with a bleed valve and a bleed hose. The tubing string was initially set in the rotary table slips with the top located approximately

4 feet above the slips. The tubing string and test tree were subsequently raised an additional 4 feet so the wireline tools would run more freely. The manual bleed valve on the lubricator was located approximately 20 feet above the rig floor. To operate this bleed valve would require lifting and lowering a person by use of an air-operated hoist. For the sake of convenience, bleeding was done through the flowline. Pressure bled down steadily to approximately 800 psi, then began to rise as indicated by pressure gauges on the lubricator and on the flowline at the rig floor manifold. This pressure rise indicated that the two closed master valves were leaking.

Blowout

At approximately the same time the bled-down pressure started to rise from 800 psi, a loud noise was heard on the rig floor. This noise was most likely caused by the wireline tools being moved inside the lubricator by a surge of gas flow into the lubricator. The bleed valve in the flowline at the rig floor manifold was then closed. At this time, gas started to escape onto the rig floor from a hammer lug union located on the flowline approximately 6 inches away from the test tree outlet. Inspection of the union after the incident showed that a groove was cut in a body part by the erosive flow of escaping gas. Next, the remote control to the sliding sleeve valve in the test tree was activated to close the sleeve valve. Flow of gas from the union into the rig floor area continued. The overall length of the flowline between the sleeve valve and the floor manifold bleed valve was approximately 50 feet. By design, the sleeve valve is opened by applying

1,000-psi nitrogen gas pressure through a control port to an internal piston area. The valve is closed by an internal compressed spring when the gas pressure is bled off. Other than the presence or absence of nitrogen gas pressure on the valve, no other device for indicating valve position was provided. There is no conclusive evidence as to whether the sleeve valve failed to close or the source of continued flow was from the gas trapped under pressure in the 50 feet of 2-inch ID flowline. With conditions for an explosion and fire present and extreme danger imminent, the order was given to close the blind-shear rams.

The blind-shear rams were closed from the control station on the rig floor. The tubing was sheared and severed. There is uncertainty as to whether the blind-shear rams initially effected a tight seal or there was a slight leak past the seal. Witnesses reported that the sight, sound, and other noticeable signs of gas escaping to the atmosphere vanished when or very shortly after the rams closed. In either case, the pressure seal was to fail in a major way approximately 2 to 3 minutes after the rams closed.

After the blind-shear rams were closed, and prior to their major failure, the decision was made to jack up the rig to raise the severed section of tubing from opposite the blind rams and then close the blind rams. The decision to jack up the rig instead of using the rig drawworks to raise the entire lubricator-test tree-tubing section assembly was made because the test tree and attached flowline were tied down with chains to the rig structure, and the presence of gas in the rig floor area created a hazardous work environment. The pipe rams were opened, and jacking operations from the control room were begun. The rig was jacked up at a rate of approximately 1 foot per minute. After jacking the rig up approximately 2 to 3 feet, the operation was stopped when the section of severed tubing above the blind-shear rams was seen being blown out of the well through the rotary table. The blind-shear rams had failed. The severed section of tubing, approximately 38 feet in length, which was blown out of the well, was bent in a "C" shape and had broken loose by snapping off the pin connection on the bottom of the test tree. (See Attachment 5.) At this time, the blind rams were closed from a remote BOP control station. No attempt was ever made to close the open HCR. There is some evidence that it was believed the HCR was already closed and some other evidence that indicates that, during this extremely dangerous situation with limited reaction time, steps to close the HCR were overlooked.

At approximately the same time the blind rams were closed, two more loud noises were heard. These noises were most likely the rig pump vibrator hose rupturing in stages below the rig floor. (See Attachment 5.) Well pressure, far in excess of 5,000 psi, reached the 5,000-psi RWP vibrator hose from the well because well pressure was communicated through the open HCR and manual valve on the kill-line side of the spool at the BOP stack, through the kill line, through a valve on the choke and kill manifold that was inadvertently left open, to and through the standpipe manifold, to and through the vibrator hose, and on to the rig mud pumps. The pressure safety valve (PSV) in the discharge line at the mud pump did not operate at its set pressure of 4,200 psi. The PSV was subsequently found functional, indicating the hose ruptured at a pressure below 4,200 psi. With the rig area engulfed by escaping gas, orders were given to abandon the rig. All 51 persons aboard the facility were evacuated without injury. Before the rig was abandoned, two emergency power shutdown switches were activated, but both switches failed to function. Time did not allow rig personnel to activate the other emergency power shutdown switches on the rig, and the generator engines were left running. Subsequent inspection showed the cause of switch failure was broken glass in one switch and corrosion damage to the other. This gas well flowed uncontrolled into the atmosphere for 17½ hours with the generator engines running, but there was no fire or explosion. It took an additional 29 hours before the well was killed with mud.

Rig Abandoned

All 51 persons aboard the rig were evacuated without injury in the two survival capsules. Personnel were evacuated to Shell Oil Company's Brazos A-23 platform and then to a shore base at Port O'Connor, Texas, via the workboat M.V. *Captain George*.

Activities to Regain Well Control

During the night of May 30, 1990, NEI personnel assessed the situation, contacted the appropriate Government regulatory agencies, and consulted with well-control specialists. At 6:00 a.m. on Thursday, May 31, 1990, three NEI personnel, two contract well-control specialists, and six Keyes-Marine personnel traveled by helicopter to Shell's A-23 platform. At approximately 8 a.m., they began travel to the rig aboard the M.V. *Captain George*. Two well-control specialists boarded the rig to assess the situation. The blind-shear rams and the blind rams were in a closed position. The lubricator connected to the test tree was seen hanging from the elevators with the pin at the bottom of the test tree broken off. Generator engines were still running because the emergency power shutdown switches failed to function. No tubing was in the hole above the closed blind-shear rams. As shown in Attachment 3, the well was flowing uncontrolled through the open HCR and manual valve on the kill line and into the atmosphere through holes in the 5,000-psi RWP 2- and 3-inch ID lines at the rig floor standpipe manifold and through a rupture in the vibrator hose. Flow had eroded through the wall of the 2-inch ID line at a 45-degree bend in the line and then impinged onto and completely eroded through the adjacent 3-inch ID fill-up line from its outside. Flow then began from the erosion hole in the 3-inch ID fill-up line.

At approximately 9 a.m., the well-control specialists left the platform by workboat to Shell's A-23 platform and then to a shore base at Port O'Connor, Texas. All parties consulted and assessed the situation. Two fire-monitoring boats and an offshore well-servicing boat were ordered to the scene. These boats were never used.

Regain of Well Control

At 11:30 a.m., the well-control specialists again boarded the rig. The manual valve on the kill line at the spool in the BOP stack was closed directly by hand. Flow from the well out through the kill line and into the atmosphere ceased. The well was now controllable. To lower and maintain the lowered pressure on surface and subsurface equipment by flowing the well, valves in the choke manifold were repositioned and the well was then diverted to flow, under control, out the choke line, through the gas buster, and into the atmosphere through a stack vent at the top of the derrick. The specialists locked down the blind rams. Keyes-Marine and NEI personnel then boarded the rig, checked for gas with portable gas detectors, shut down the generator engines, and surveyed damages. At 4:30 p.m., all personnel left the rig and returned to Port O'Connor. The well continued to flow during the night through the gas buster and into the atmosphere out the stack vent at the top of the derrick.

Well Killed

At 7:00 a.m., on June 1, 1990, three well-control specialists boarded the platform. The well was still flowing through the gas buster and out the stack vent. At 7:30 a.m., all necessary personnel and equipment required for the kill operation were loaded onto the platform from the workboat. The top pipe rams were replaced with blind rams to be used as a backup during the kill operation. A pressure gauge was installed on the casing head below the blind-shear rams. The gauge read 500 psi. All the lines to the manifolds and spool in the BOP stack were made ready to kill the well. At 3:00 p.m., all nonessential personnel were sent to stand by at the escape capsule. At 3:30 p.m., the blind-shear rams were opened. Fifty barrels of 18.0 ppg mud, followed by 28 barrels of 16.7 ppg mud, were pumped into the well through the choke line into the casing and, from there, down the tubing. Maximum pump pressure was 3,600 psi. Once kill mud reached the open perforations, the pumps were shut down and the pressure was bled off. The well was dead at approximately 4:30 p.m. The choke line was closed and pressures were monitored for the night.

Well Re-entered and Completed

The well was later re-entered. The top of the severed test string was found 14 feet below the blind-shear rams. The string was intact and in a sound condition. The string was retrieved, a production tubing string run, and the well completed as a gas producer.

Pollution

Approximately 12 barrels of 17.0-ppg oil-base mud were blown out from the well during the incident. The estimated volume of mud blown out is the same as the calculated volume of mud (12 barrels) contained in the casing, BOP stack, and riser above the top of the severed tubing. Most of this mud was found on the rig surfaces and was cleaned up. Nearly all of the oil-base mud was discharged through a rupture in the vibrator hose. The point of rupture in the hose was located on the next deck level below that of the rig floor. The discharge point location being below the rig floor deck served to reduce significantly the amount of oil-base mud that otherwise may have reached the ocean.

Equipment Failure Analysis

Subsequent tests on the test tree and its component valves by an independent testing laboratory showed that the valve cores and seals in the inlet and port areas of both master valves were damaged and would hold no pressure. The damage is attributable to erosive flow through the valves while in a closed position. Before the shipment of the test tree to the laboratory, numerous CIBP fragments, including the slips, were found loose inside the test tree and were removed. All but the top part of the wireline tool string was found resting on the closed upper master valve in the test tree. Evidence suggests that when the master valve failed, the surge of gas into the lubricator propelled the tools against the top of the lubricator. The impact broke the tool string near its top, and the tool string fell approximately 46 feet onto the closed upper master valve in the test tree. The impact shattered the CIBP and delivered a jar to the test tree. The jar was transferred to a flow-line union through a direct, short, and rigid pipe connection between the test tree outlet and the union. The union then began to leak. In the laboratory, foreign material was found loose in the body of the upper master valve and in the outlet port of the remotely operated sleeve valve. The foreign material consisted of four irregularly shaped pieces of metal approximately ¼-inch wide and ranging in length from ¼ to ¾ inches. Some of the pieces clearly showed striations on their surface, indicative of machining and of being CIBP fragments. There is no evidence that the foreign material interfered with the operation or pressure integrity of any valve at the time of the accident. Both the swab valve and the sliding sleeve valve in the test tree passed laboratory tests for operation and pressure integrity.

Subsequent investigation of the severed tubing showed that it had been crimped into an oval shape where sheared, with a small tooth-shaped nub of torn metal remaining at the place sheared. Inspection of the blind-shear rams after the incident showed a resilient seal on one ram was completely destroyed. Damaged areas of ⅛ to ¼ inch in size, caused by erosive flow, were found on each side of the other ram.

Injuries and Damages

There were no injuries to personnel. Equipment damage was limited primarily to the ruptured vibrator hose, blind-shear rams, and piping at the standpipe manifold. Other losses included the costs of lost rig time, support personnel and equipment, and rig cleanup. Total cost of equipment damage and other losses is estimated at $350,000.

Summary Conclusions

Multiple and sequential equipment failures, combined with the specific open or closed position of certain valves in the well-control system, eventually led to a series of uncontrolled flows of gas into the atmosphere.

When trouble first began, production testing of a zone of interest in the newly drilled gas well had just been completed. The zone was tested through perforations in the casing. A test tree and lubricator were mounted on the tubing test string above a BOP stack. To monitor for tubing leaks, the pipe rams were closed and a pressure of 1,000 psi was being held on the casing annulus through the kill line. The kill line was open all the way from the casing annulus to the rig mud pumps. An unsuccessful wireline run to set a tubing plug had just been made. The wireline tools were inside the lubricator. The upper master valve on the test tree was closed, and the assembly above the closed valve was being bled down through the test tree outlet and flowline. The lower master valve was also closed, although it was known at the time that this valve lacked pressure integrity.

The sequence of events is as follows. Please refer to Attachment 3.

1. The shut-in surface well pressure of 9,200 psi inside the upper portion of the test tree and lubricator was being bled down to 800 psi when the pressure seal in the upper master valve in the test tree failed under the

8,400-psi pressure differential. The resultant surge of gas into the lubricator propelled wireline tools inside the lubricator against the top of the lubricator. The tool string broke near its top, allowing the tools to fall onto the closed upper master valve in the test tree.

2. The jarring effect of the upward and downward blows by the wireline tools to the test tree and lubricator assembly was transferred to a flowline union located near the test tree outlet. As a result, the union began to leak. The rig floor area rapidly became engulfed with escaping gas.

3. The manual bleed valve on the flowline at the floor manifold was closed, and the remote control to the sliding sleeve valve at the test tree outlet was activated to close the valve, but flow out of the union continued. There is inconclusive evidence as to whether the sleeve valve failed to close or the source of continued flow was from the gas trapped under pressure in the 50 feet of 2-inch ID flowline between the test tree and the closed valve on the flowline at the floor manifold.

4. To stop flow from the union and to confine well pressure to within the casing below the BOP stack, the blind-shear rams were closed. The rams severed the tubing and apparently held pressure initially but were to fail after approximately two minutes. In preparation to close the blind rams, the pipe rams were opened and operations were begun to jack up the rig to raise the severed section of tubing above the blind

rams. During the jacking up of the rig, the blind-shear rams failed. Well pressure and flow velocity blew the 38-foot long section of severed tubing out of the well through the rotary table and onto the rig floor. The well then flowed into the atmosphere out the top of the BOP stack.

5. Jacking operations were stopped, and the blind rams were closed. Well flow up through and out the top of the BOP stack stopped.

6. With the blind rams holding, 9,200-psi shut-in surface well pressure was now imposed on and ruptured a 5,000-psi-rated RWP vibrator hose in the mud pump discharge line below the rig floor. The well then flowed uncontrolled into the atmosphere. The flow route was from the casing, out the open HCR and manual valve on the spool in the BOP stack, through the kill line, on through a valve in the choke-and-kill manifold that was inadvertently left open, to and through the standpipe manifold, and on to and out of the rupture in the vibrator hose. Continued flow caused erosion completely through two lines near the standpipe manifold on the rig floor, creating two more points of gas escape into the atmosphere.

7. No attempt was ever made to close the HCR. Some evidence indicates that the HCR was believed to be already closed, and some other evidence indicates that in the extremely dangerous situation with limited reaction time, steps to close the HCR were overlooked.

8. All 51 persons aboard the rig were safely evacuated in two escape capsules.

9. Well flow was stopped when a well-control specialist boarded the rig while the well was blowing out and closed, directly by hand, the manual valve on the kill line at the spool in the BOP stack.

10. To lower and maintain the lowered pressure on surface and subsurface equipment by flowing the well, valves in the choke-and-kill manifold were repositioned, and the well was then diverted to flow, under control, out the choke line, through a degasser, and into the *atmosphere out a vent at the top of the derrick. Necessary* preparations were made, and the well was killed by opening the blind-shear rams and pumping kill-weight mud to the perforations through the choke line into the casing and, from there, down the tubing.

11. The well had flowed uncontrolled into the atmosphere for approximately 17½ hours. An additional 29 hours elapsed from the time uncontrolled flow into the atmosphere was stopped and the time the well was killed.

12. There were no injuries to personnel and no fires or explosions. Approximately 12 barrels of oil-base mud were blown out of the well, and most of the mud landed on the rig surfaces and was cleaned up.

13. Estimated total costs arising from equipment damage, hired support personnel and equipment, lost rig time, and rig cleanup were $350,000.

14. The well was later completed as a gas producer.

Recommendations

It is recommended that the MMS Gulf of Mexico OCS Region issue a Safety Alert that would describe the circumstances surrounding this accident, summarize its causes, and suggest measures to prevent recurrences of a similar nature. The Safety Alert would include the following suggestions:

1. If a well with a surface BOP stack and an anticipated surface pressure greater than 5,000 psi is to be production tested, consideration should be given to equipping the test tree assembly with (a) a surface-controlled, tubing-retrievable safety valve inside the test string below the BOP stack and (b) two or more master valves, a swab valve, and a remotely controlled actuator on at least one of the master valves.

2. When it becomes known that any master valve or other component in a test tree or related flow-control equipment is defective in function or pressure integrity, operations should be suspended and the well secured until system integrity is restored.

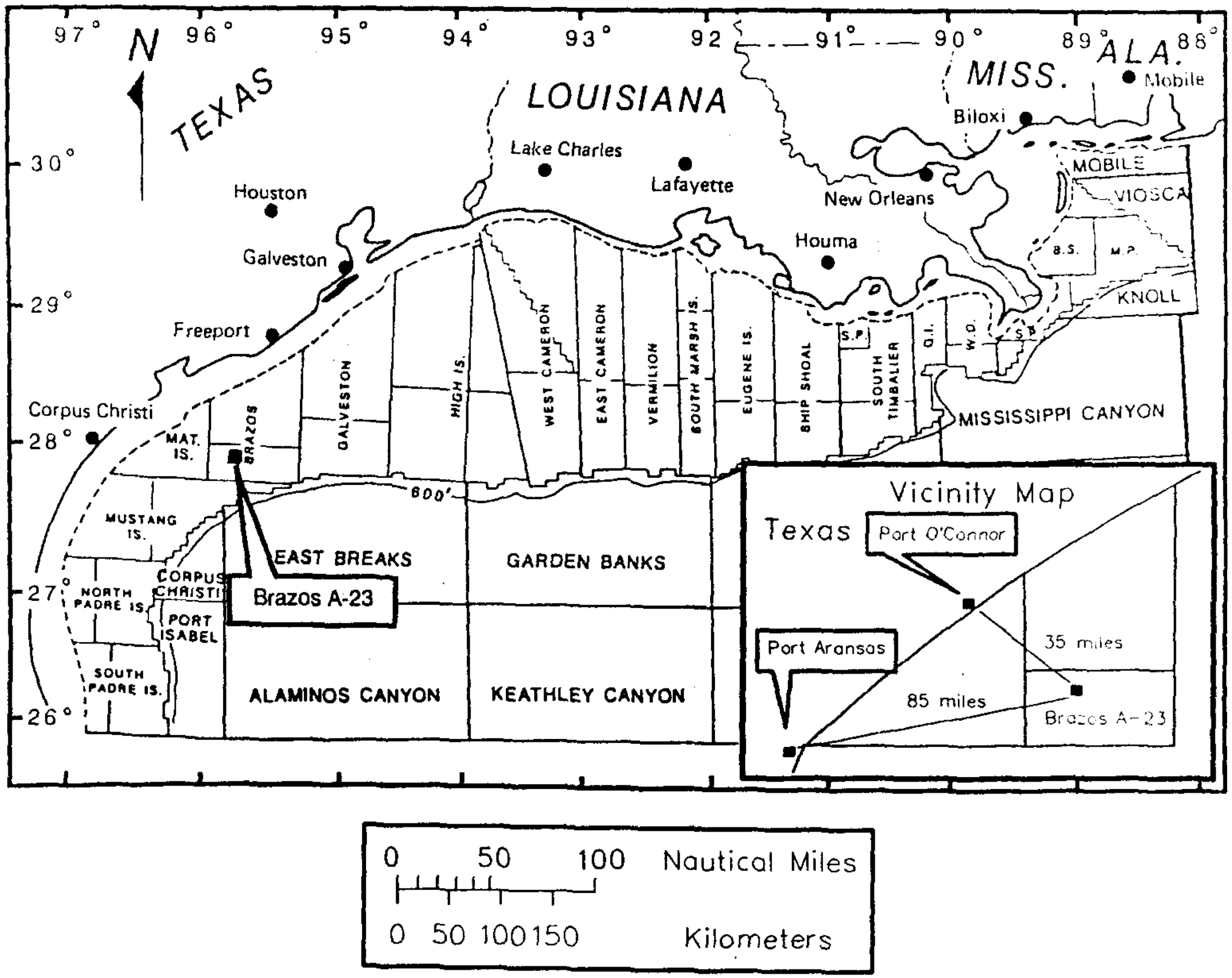
3. The lubricator bleed-off valve should be placed and used as close to the lubricator as practicable. The reason is to avoid the risk associated with imposing lubricator and possibly sustained well pressure on the bleed line by the use of a valve located on the bleed line distant from the lubricator.

4. During production testing with surface pressures greater than 5,000 psi, caution should be exercised that (a) flanges or other impact-resistant type connections at and near the test tree outlet are used in lieu of hammer lug unions, (b) ample flexibility in the flowline is provided, and (c) measures are taken to protect the test tree from internal impacts such as from wireline tools and from external impacts such as from falling and thrown objects.

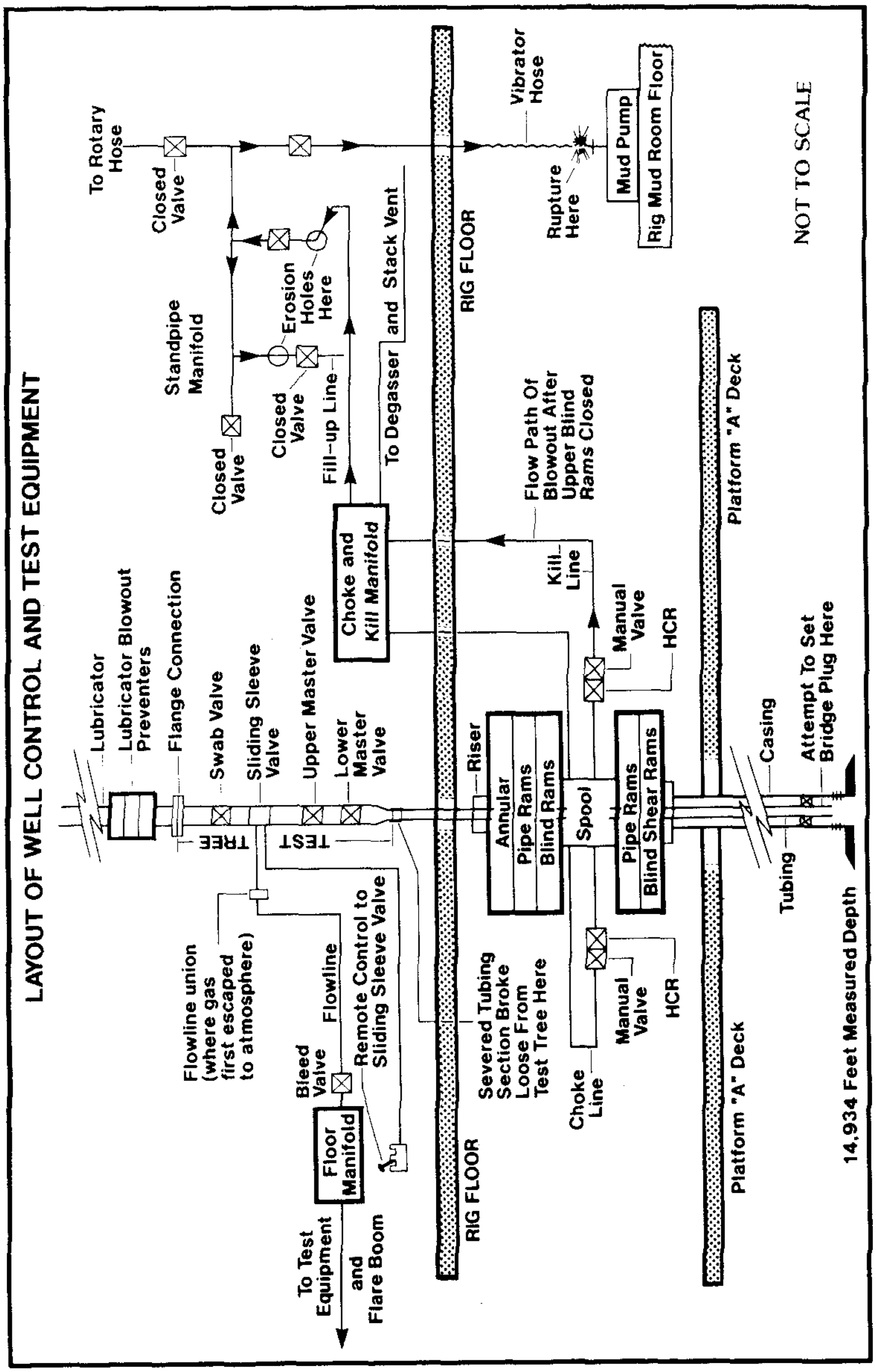
5. The selection and arrangement of rig and well flow-control devices at the interfaces, if any, of high- and low-pressure systems should be so designed as to minimize human error and equipment failure risks of high-pressure sources entering and overpressuring lower-pressure-rated equipment.

Attachment 1

Aerial view of the blowout well.

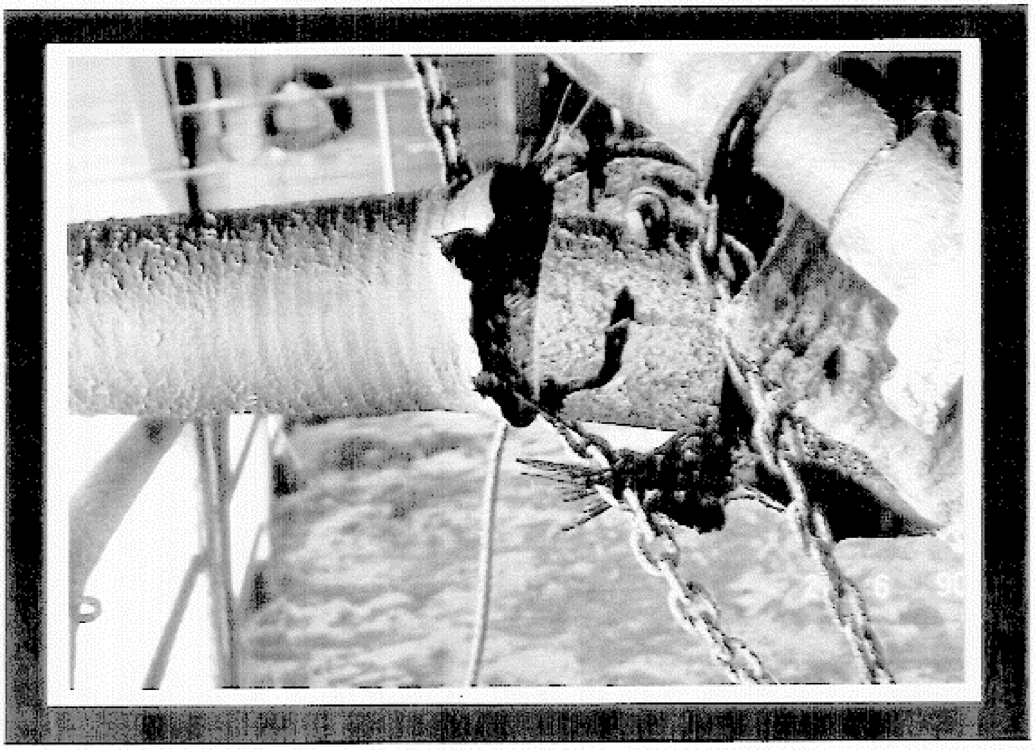


Location of Lease OCS-G 3938, Brazos Block A-23.

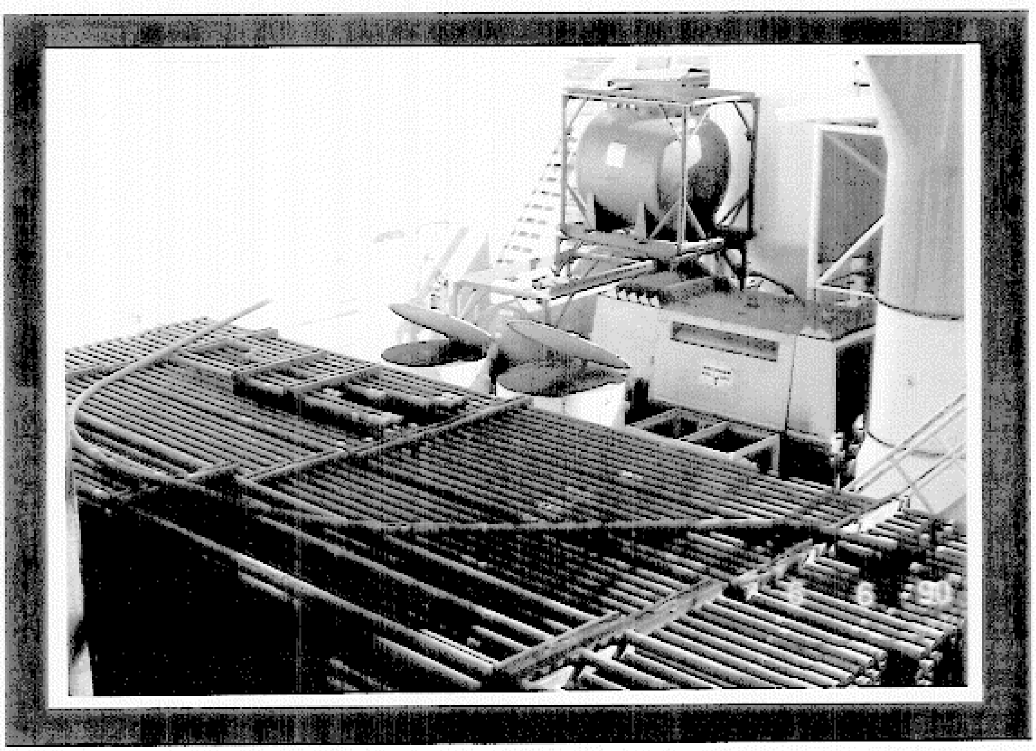


LAYOUT OF WELL CONTROL AND TEST EQUIPMENT
Lubricator
Lubricator Blowout Preventers
Flange Connection
Swab Valve
Sliding Sleeve Valve
Upper Master Valve
Lower Master Valve
TREE
TEST
Riser
Annular
Pipe Rams
Blind Rams
Spool
Pipe Rams
Blind Shear Rams
Casing
Tubing
Attempt To Set Bridge Plug Here
14,934 Feet Measured Depth
Flowline union (where gas first escaped to atmosphere)
Flowline
Bleed Valve
Remote Control to Sliding Sleeve Valve
Floor Manifold
To Test Equipment and Flare Boom
Severed Tubing Section Broke Loose From Test Tree Here
RIG FLOOR
Choke Line
Manual Valve
HCR
Platform "A" Deck
Kill Line
Manual Valve
HCR
Flow Path Of Blowout After Upper Blind Rams Closed
Choke and Kill Manifold
To Degasser and Stack Vent
Fill-up Line
Closed Valve
Closed Valve
Standpipe Manifold
Erosion Holes Here
Closed Valve
To Rotary Hose
RIG FLOOR
Vibrator Hose
Rupture Here
Mud Pump
Rig Mud Room Floor
Platform "A" Deck
NOT TO SCALE

Test tree as seen above the rig floor after the blowout. Note the tie-down chains, bottom center.



Ruptured rig pump vibrator hose as seen from below the rig floor.



38-foot length of severed 2 $^{7}/_{8}$-inch tubing as seen on the pipe racks after the blowout.

As the Nation's principal conservation agency, the Department of the Interior has responsibility for most of our nationally-owned public lands and natural resources. This includes fostering sound use of our land and water resources; protecting our fish, wildlife, and biological diversity; preserving the environmental and cultural values of our national parks and historical places; and providing for the enjoyment of life through outdoor recreation. The Department assesses our energy and mineral resources and works to ensure that their development is in the best interests of all our people by encouraging stewardship and citizen participation in their care. The Department also has a major responsibility for American Indian reservation communities and for people who live in island territories under U.S. administration.